Studies of Natural Gas Resources in Deep Sedimentary Basins

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INTRODUCTION

For strategic, economic, and environmental reasons, many U.S. drilling frontiers deserve further review. One such frontier is natural gas in deep sedimentary basins. Deep natural gas resources are distributed throughout many basins with widely different geological environments (Figure 1). According to the Potential Gas Committee (1999), the U.S. contains a total potential resource of 1,037 trillion cubic feet (Tcf) of natural gas resources including the growth of reserves in known fields and undiscovered resources. In 1995, the USGS estimated 1,074 Tcf of technically recoverable gas resources in the U.S. including gas as proved reserves, reserve growth in gas fields, undiscovered conventional and continuous gas, and gas in small fields (U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995). Dyman and others (1996) identified about 113 Tcf of deep gas (gas in undiscovered fields below 15,000 feet) from 162 deep conventional (55 Tcf) and 11 deep continuous-type plays (58 Tcf) in the U.S. based on the results of the USGS 1995 National Assessment. A more precise understanding of U.S. resources of deep gas will provide valuable economic and strategic information for future planning. In addition, an understanding of the Worldwide distribution of deep gas will provide a strategic perspective from which to view U.S. resources.

The word "deep" is used in a relative sense here, and its meaning varies for different tasks in this project and for different basins or regions. For the purpose of this paper, the word deep is defined to include all resources residing below 15,000 feet (~4.5 km), but may also refer to processes occurring at great depths, relating to resources now residing in shallow basin margins. Deep is used to focus a series of tasks in this project because it is an important classification criterion for both industry and governmental planning organizations, and the term implies important economic considerations because deep drilling frontiers are very expensive, and new technology advancements may improve their economic success.

This project evolved as an outgrowth of work on two previous projects, one funded by the Gas Research Institute (GRI) (Dyman and others, 1997) and the other by the U.S. Department of Energy (DOE) (Rice and others, 1992) on the geologic controls of deep gas. During both projects, important new research directions were identified. Many of these directions are addressed in this project. A precise understanding of the geologic controls governing the origin and distribution of deep natural gas resources may have a significant impact on the future energy resources of this Nation and the World.

This project is a two-year project which began in April 1998 and is closely related to another DOE-sponsored project dealing with the distribution of “new” basin-centered gas accumulations in U.S. basins regardless of depth (DOE project no. DE-AT26-98FT0031 entitled “Basin-Centered Gas Systems of the U.S.”-- V.F. Nuccio project chief). Results described in this report represent activities of Phase 1 or the first year of the project. Results (1) describe and analyze the geologic factors that control the distribution of deep conventional and unconventional gas accumulations in sedimentary basins of the U.S., and (2) characterize the distribution of deep conventional gas Worldwide.

Petroleum Resource Assessments

The USGS periodically conducts geologically- and probabilistically-based resource assessments and has completed four assessments for the Nation and the World in the last 20 years. This experience in conducting petroleum resource assessments forms the basis of much of our work on deep natural gas resources.

This project describes the potential for deep basin-centered gas accumulations in sedimentary basins of the U.S. based on results of these petroleum assessments, data from the published literature, and computerized well and reservoir data files. The USGS is currently re-evaluating the resource potential of selected deep basins and plays in the U.S. due to changing geologic perceptions and new data since the completion of the USGS 1995 National Petroleum Assessment.

Newly defined basin-centered accumulations in basins of the U.S. may result in new plays based on an analysis of data available since the USGS 1995 National Assessment (U.S. Geological Survey National Oil and Gas Assessment Team, 1995). These basin-centered gas accumulations vary qualitatively from low to high risk and may/may not survive rigorous geologic scrutiny leading toward a full geologic assessment based on plays.

Continuous-Type Accumulations

Continuous-type accumulations are large single fields having spatial dimensions equal to or exceeding those of conventional plays. They cannot be represented in terms of discrete, countable units delineated by downdip hydrocarbon-water contacts (as are conventional fields). The definition of continuous accumulations is based on geology rather than on government regulations defining low permeability (tight) gas. Common geologic and production characteristics of continuous accumulations include their occurrence downdip from water-saturated rocks, lack of obvious trap or seal, relatively low matrix permeability, abnormal pressures, large in-place hydrocarbon volumes, and low recovery factors (Crovelli and Balay, 1995; Schmoker, 1996).

Continuous plays were treated as a separate category in the USGS 1995 National Petroleum Assessment and were assessed using a specialized methodology (Crovelli and Balay; Schmoker, 1996). These continuous plays are geologically diverse and fall into the following categories: coal-bed gas, biogenic gas, fractured shale gas, and basin-centered plays. Only continuous-type basin-centered gas plays comprise significant future undiscovered resources in deep sedimentary basins.

Assessment of continuous plays is based on the concept that an accumulation can be regarded as a collection of hydrocarbon-bearing cells. In the play, cells represent spatial subdivisions defined by the drainage area of wells. Cells may be productive, nonproductive, or untested. Geologic risk, expressed as play probability, is assigned to each play. The number of untested cells in a play, and the fraction of untested cells expected to become productive (success ratio) are estimated based on available production data, and a probability distribution is defined for EURs for those cells expected to become productive cells. The combination of play probability, success ratio, number of untested cells, and EUR probability distribution yields potential undiscovered resources for each play. Refer to Schmoker (1996), Crovelli and Balay (19095), and Schmoker and others (1995) for a detailed discussion of continuous-type plays and their assessment.

In 1995 the USGS defined 100 continuous-type plays with oil and gas reservoirs in sandstones, shales, chalks, and coals for all depth intervals. Of the 100 identified plays assessed, 73 were gas plays. Estimates of technically-recoverable gas resources from continuous-type sandstones, shales, and chalks range from 219 Tcf (95th fractile) to 417 Tcf (5th fractile), with a mean estimate of 308 Tcf. Estimates of technically-recoverable gas resources from coals in the lower-48 States range from 43 Tcf to 58 Tcf, with a mean estimate of 50 Tcf (U.S. Geological Survey National Oil and Gas Assessment Team, 1995). However, continuous coalbed gas resources will not be discussed further in this report because they are not deep. Continuous-type plays either not assessed or not identified in many areas or regions of the U.S. such as in Alaska, the Wind River, Bighorn, and Hanna basins of the Rocky Mountain region, the Anadarko basin of Oklahoma, and the Fort Worth basin of central Texas. Table 1 summarizes potential new deep continuous-type gas accumulations in the U.S.

Four categories of continuous-type plays can be identified with respect to new data and perceptions since the USGS 1995 National Petroleum Assessment: (1) Continuous-type plays that were correctly identified as such, assessed in 1995, but need to be updated because of new data. These plays will not be addressed further in this report. (2) Continuous-type plays that may have been identified incorrectly as conventional plays and assessed as such in 1995. (3) Continuous-type plays that were identified as such in 1995 but not assessed because of a lack of data. (4) New continuous-type plays that were not even identified in 1995.

Continuous Accumulations and Reserve Growth

In the traditional terminology of petroleum resource assessment, undiscovered resources are those postulated to exist outside of known fields, whereas inferred reserves are those forecast to be added to known fields as they are further developed (i.e. reserve growth). However, in the case of continuous accumulations, the distinction between undiscovered resources and reserve growth can be blurred. For example, in the USGS 1995 National Assessment, the existence and location of many of the continuous accumulations considered were well known, implying that the assessment procedure was an exercise in estimating reserve growth. However, the existence and location of some continuous accumulations were not at all certain, but were postulated from geologic knowledge and theory, so that the assessment procedure in these cases was an exercise in estimating undiscovered resources. In the context of this paper, some of the potential continuous gas plays are not well understood, but others have been drilled extensively. The assessment of the former resource constitutes undiscovered resources, whereas the latter resource constitutes an exercise in the estimation of reserve growth.

PROJECT OBJECTIVE

The objective of this project is to employ current and new procedures in resource assessment, quantitative production analysis, wireline log interpretation, organic geochemistry, and basic framework geology including reservoir characterization to better understand the nature and distribution of deep natural gas resources. Emphasis is placed on obstacles to deep drilling and development of predictive models that can be used to better identify future exploration and production strategies for industry and to provide more precise resource assessments.

The project is subdivided into seven research tasks: (1) New Deep Unconventional Gas Accumulations, (2) Undiscovered Resources for Deep Gas Plays, (3) Petrophysical evaluation of Deep Reservoirs Using the "Gas Effect", (4) Geochemical Analysis of Deep Source and Reservoir Rocks, (5) Play Definition and Uncertainty of Deep Reservoirs and Plays, (6) Deep Gas and the World Petroleum Assessment, and (7) Directions for Future Study. The first six tasks are geochemical, geological, and petrophysical studies for one or more basins, regions, reservoirs, or plays. The seventh task will integrate results from the earlier tasks to answer questions about future directions of study and frontier drilling prospects during Phase 2 of this project. This report summarizes the first phase of the project (April 1998-March 1999).

RESEARCH TASKS--APPROACH

Task 1: New Deep Unconventional Gas Accumulations

The USGS did not define or assess unconventional (continuous-type) deep gas plays in some basins in its 1995 National Petroleum Assessment because of (1) a lack of data or (2) varying interpretations at the time that dealt with the conventional versus continuous nature of plays. As a result, we are compiling an inventory of deep continuous-type (basin-centered) accumulations in basins of the U.S. during Phase 1 of this project. The inventory includes geologic and production information about each accumulation and the potential for future play definition and assessment. Accumulations are rated as high, medium, or low based on the following criteria: (1) the amount of data available for an area, and our level of confidence in the data, (2) the 30-year impact of the potential accumulation, (3) the magnitude or size of the potential resource, (4) the geologic risk (e.g., depth, remoteness), (5) national distribution, and (6) the relationship to the USGS 1995 oil and gas assessment (have our perceptions about an area changed since then?).

During Phase 2 of this project, the highest priority accumulations will be evaluated in detail using well data and production characteristics. This project also relies on results from DOE project DE-AT26-98FT40031 which characterizes basin-centered gas systems regardless of depth in the U.S.

Task 2: Undiscovered Resources for Deep Gas Plays

Resource estimates are expressed as probability distributions for plays and represent the overall uncertainty in the estimation process. The uncertainty in resource estimates results from the lack of geologic and production data for plays and provinces, the experience and opinions of province geologists, and factors associated with assessment methodology. During Phase 1 of this project, we are identifying the range of estimates as fractiles of probability distributions in undiscovered conventional resources in natural gas plays for several regions identified in the 1995 USGS National Petroleum Assessment.

During Phase 2, conventional gas plays will be compared to continuous gas plays, and a priority list will be presented for play-re-evaluation. A ranking of plays based on relative uncertainty will prove helpful for exploration and development planning and for petroleum assessment.

Task 3: Evaluation of Deep Reservoirs Using the "Gas Effect"

Problems exist in evaluating prospective low permeability gas wells, especially at great depths. Nuclear porosity tools are used to investigate the differences in porosity and permeability in shallow versus deep well bores. During Phase 1 of this project, predictive models are being developed to identify the best procedures for evaluating reservoir rocks at great depths (as compared to shallow depths).

The relation of neutron, density, and gamma-ray tool responses to the presence of clay and gas in a formation is expressed by plotting the difference between neutron and density porosity (N-D) against gamma-ray intensity (GRI). This method has been used in the past to distinguish gas-producing from water-producing intervals in very shaly formations where conventional log-analyses are ineffective. Effectiveness of the crossplot depends on the existence, close proximity, and identification of water-saturated zones with geologic and production characteristics similar to those of prospective gas-producing intervals.

During Phase 2 of the project, the model will be applied to deep Morrow reservoirs of the Anadarko basin and reservoirs of the deep Gulf Coast region to determine if new deep gas resources can be identified.

Task 4: Geochemical Analysis of Deep Source and Reservoir Rocks

For task 4, gas-oil ratios (GORs) are being analyzed using published hydrous pyrolysis data from deep source rocks for economic evaluation and resource assessment. GORs vary significantly based on source-rock composition, thermal history during hydrocarbon generation, and the overall geologic history of the basin. Predicting the GOR of a petroleum play is important in evaluating the economics for an exploration venture and the input data for petroleum resource assessment. GORs are presented from hydrous-pyrolysis experiments conducted on immature source rocks and analyzed for how they are affected by kerogen type and thermal maturity during oil generation. Emphasis is placed on the role of increasing depth.

Key questions to be answered include: Can models be developed that allow us to predict volumes of gas generated based on depth, thermal maturity and kerogen type? Can hydrous-pyrolysis experiments be used to estimate the amount of gas generated under different thermal and source rock conditions?

During Phase two of the project, the role of water in gas generation will be evaluated using laboratory results from hydrous pyrolysis experiments.

Task 5: Play Definition and Uncertainty of Deep Reservoirs and Plays

Continued exploration interest in deep gas plays has prompted a re-evaluation of USGS plays assessed in the 1995 National Petroleum assessment. During Phase 1 of the project, gas plays are being evaluated on the level of uncertainty of the probability distributions of their undiscovered resources. Gas plays are being evaluated on differences in depth, lithology, and other geologic and production factors (see also Task 2 discussion).

Work during Phase 2 of this project will include a re-evaluation of the geologic framework of reservoir rocks with emphasis on the reservoir changes that occur with increasing depth and a reclassification of deep gas plays based on geologic characteristics. Emphasis will be placed on re-evaluating Jurassic and Cretaceous clastic plays of the Louisiana-Mississippi Salt Basins Province including the Cotton Valley Group and Travis Peak Formation plays. In 1995, the USGS identified five Cotton Valley plays, but only one (the Cotton Valley Blanket Sandstones Play) was assessed as a continuous-type play. A re-assessment of other Cotton Valley plays as continuous could significantly change the gas resource base for the onshore Gulf Coast region.

Task 6: Deep Gas and World Petroleum Assessment

The USGS World Petroleum Assessment Project is currently assessing undiscovered oil and gas resources for the most important 100 petroleum provinces of the World (extrapolated out to 30 years into the future). During Phase 1 of this project, the USGS is developing a procedure and computer software to allocate resources by depth.

During Phase 2, newly-released World resource estimates resulting from the World Petroleum Assessment Project will be subdivided into depth slices. Resources by depth interval will be compiled by petroleum region, province, and nation. The total resource estimates needed for depth-slice allocation will not be available until near the end of the second year of this project when they become publicly available.

Task 7: Directions for Future Study

During Phase 2 of this project, results from the first six tasks will be integrated in order to summarize directions for future study. Questions to be answered include: Where do new deep undiscovered gas resources reside in the U.S.? What regions of the U.S. deserve the most attention with respect to future deep drilling? What are the primary controls governing the generation and distribution of deep gas, and how can we use this information to improve exploration methods and natural gas assessments? What can we learn about deep gas accumulations Worldwide to improve deep gas recovery in the U.S. Data on deep gas from the other nations will provide the basis for this summary.

SUMMARY OF PROJECT RESULTS—PHASE 1

Task 1: New Deep Unconventional Gas Accumulations

A priority list of potential deep basin-centered gas accumulations was prepared from a geologic and production evaluation by USGS Survey staff starting from the results of the 1995 National Petroleum Assessment (Gautier and others, 1996). This effort also relied on results from DOE project DE-AT26-98FT40031 which characterizes basin-centered gas systems regardless of depth throughout the U.S. For that project, we identified thirty-three potential basin-centered gas accumulations throughout the U.S. They include the: Sacramento/San Joaquin basins; Raton basin; Rio Grande rift; Anadarko basin; onshore Gulf Coast basin, Jurassic-Cretaceous Travis Peak and Eagle Ford Formations and Cotton Valley Group; Columbia basin/West Flank of the Cascade Mountains; Michigan basin; Cook Inlet basin, Alaska; Permian basin; Hanna basin; Paradox basin (Pennsylvanian shales); Western North Slope of Alaska, Central Alaska; Wasatch Plateau; Puget Sound basin; Modoc basin, Northern California; Santa Maria basin, Monterey Formation; Los Angeles basin; Salton trough; Great Basin, Tertiary basins; Snake River downwarp; Paradox basin, Precambrian Chuar Group; Denver basin; Park basins, Colorado; North end of San Rafael Swell, Utah, Cretaceous Dakota Formation; Central Montana, Sweetgrass arch; Midcontinent rift; Arkoma basin; onshore Gulf Coast basin, Austin Chalk; Appalachian basin, Clinton-Medina and older Formations; Eastern U.S. Triassic Rift basins; and the Black Warrior Basin.

We summarized the geologic setting and data favoring the existence of potential basin-centered gas accumulations with respect to the USGS 1995 Petroleum Assessment. For each potential accumulation, we established whether new gas resources could be assessed if more data became available.

Table 1 contains a list of deep basins/areas that were evaluated for the presence/absence of a deep basin-centered gas accumulation based on work from project DE-AT26-98FT40031. The deep basins identified in Table 1 were reviewed by the USGS and grouped into three categories (high, medium, and low potential) based on the following criteria: (1) the amount of available data and overall level of confidence in that accumulation, (2) the 30-year impact of the potential accumulation on the Nation's endowment (Can we expect gas resources within the next 30 years from this accumulation?), (3) the magnitude of the potential resource, (4) the geologic risk (extreme depth, infrastructure, remoteness etc.), (5) the National distribution of accumulations, and (6) the relationship to the USGS 1995 National Petroleum Assessment (Have our perceptions changed about an accumulation?).

Task 2: Undiscovered Resources for Deep Gas Plays

Uncertainty in petroleum resource estimates can be subdivided into five broad areas: (1) compiling geologic and production data at the province level; (2) identifying and describing petroleum plays; (3) risking hypothetical plays; (4) estimating the sizes, numbers, and types of undiscovered accumulations; and (5) aggregating petroleum estimates. An analysis of these five areas of uncertainty provides insight into how resource assessments are conducted and helps answer important questions including: Are the play estimates of some province geologists more uncertain than the estimates of others? Can we define quantitative measures that capture uncertainty? Can we rank plays in an assessment based on their relative uncertainty? Can we identify the relative degree of uncertainty in plays with specific geologic and production characteristics?

We introduce a dimensionless uncertainty coefficient (UC) to compare the relative uncertainty of undiscovered conventional gas resource volumes of plays. The uncertainty coefficient is defined as:

$$UC = (F5 - F95) / MEAN$$

where F5 and F95 are fractiles of a probability distribution representing the estimate of undiscovered non-associated gas for each gas-bearing play, and MEAN represents the mean value of that estimate (Dyman and Schmoker, 1996; Crovelli and Balay, 1996). F95 represents a 19 in 20 chance and F5 represents a 1 in 20 chance of the occurrence of at least the resource amount identified. Use of the uncertainty coefficient is based on the assumption that the fractile range of the undiscovered resource for each play probability distribution (F5-F95) incorporates all areas of uncertainty that may be introduced into the assessment process.

New and useful information from the USGS 1995 National Petroleum Assessment is revealed when data on uncertainty are analyzed. Figure 2 is a plot of UC versus mean volume of undiscovered non-associated gas for each of 236 conventional gas-bearing plays from the USGS 1995 National Petroleum Assessment. The upper right-hand portion of the plot is shaded to represent larger-sized relatively uncertain plays (UC>2.0 and resource> 1 Tcf of gas). Larger plays tend to be more certain than smaller plays. Of the 10 largest plays with respect to undiscovered resource, five are from the northern Alaska province (plays 111, 109, 105, 102, and 106), four are from Gulf Coast provinces (plays 4709, 4723, 4903, and 4727), and one is from the Permian basin province (play 4401). These 10 plays have a combined resource of 77.5 Tcf of gas. Only one of the largest plays has a UC much higher than 2.0 (play 105; UC=2.32).

The most uncertain plays tend to be small with respect to undiscovered gas resources. The 10 most uncertain plays have a total combined undiscovered conventional resource of only 2.8 Tcf of gas. These plays are primarily hypothetical (no proven production in the play), occur in 9 widely distributed provinces, contain primarily clastic reservoirs, and are structurally controlled. These uncertain plays, although small, need to be re-evaluated from a geologic and engineering perspective to more precisely estimate their future resource potential.

Task 3: Evaluation of Deep Reservoirs Using the "Gas Effect"

The "gas effect" is a geophysical-tool response to gas in a formation, and occurs whenever gas is present. On well logs, the gas effect is often manifested as a visual "crossover" of neutron- and density-porosity curves. As clay volume and associated bound water increase in a formation, neutron- and density-porosity curves separate until the crossover no longer occurs, and the gas effect, although still present, is no longer detectable. An alternative, empirical approach uses a crossplot of neutron porosity minus density porosity versus gamma-ray intensity to detect and measure the gas effect regardless of clay content (Figure 3).

The magnitude of the gas effect is directly related to the bulk volume of gas present. Therefore, the gas effect can substitute for water-saturation determinations as a qualitative measure of gas concentration and an indicator of production potential. This system has an advantage over conventional log analysis in areas, such as the shallow Cretaceous of the northern Great Plains, where clay volume makes water-saturation determinations unreliable. (Phase 2 testing will include deep Morrow reservoirs of the Anadarko basin.)

The crossplot is used to separate the effects of gas and clay-bound water, and to isolate the gas effect for calibration. An overlay is used in combination with the crossplot to establish a baseline from which to measure and scale the gas effect into 12 indexed levels of magnitude. The index links the gas effect to actual gas production, and provides an estimate of production potential for a broad range of reservoir conditions.

Task 4: Geochemical Analysis of Deep Source and Reservoir Rocks

During hydrous pyrolysis experiments, oil-prone source rocks (e.g. Type-I, II, and IIS kerogen) generate gas-to-oil ratios (GORs)between 382 and 2,381 standard cubic feet/barrel (scf/bbl) (Henry and Lewan, in press).

Source rocks with Type-III kerogen generate higher GORs than source rocks with more oil prone kerogen during oil generation. However, the more oil prone kerogens can generate twice as much hydrocarbon gas per gram of organic carbon than more gas-prone Type-III kerogen. During oil generation, GORs determined in closed-system anhydrous pyrolysis increase with increasing temperature, and GORs determined by hydrous pyrolysis decrease with increasing temperature. As a result, hydrous pyrolysis GORs indicate that petroleum accumulations with GORs between 1,500 and 3,000 scf/bbl can be generated during the early stages of oil generation. Conversely, anhydrous-pyrolysis GORs indicate that petroleum accumulations with GORs greater than 2,000 scf/bbl can only be formed near the end of oil generation.

Task 5: Deep Gas and World Petroleum Assessment

A probabilistic method for subdividing resource estimates by depth was developed (Crovelli, 1999). The software program, called Deep Energy Estimated Percentages (DEEP), uses a median-based triangular probability distribution as a probability model for drilling depth to estimate the percentages of petroleum resources below various depths or depth cutoffs, and also, between depth cutoffs. The standard characterizing parameters for the triangular probability distribution include the minimum, maximum, and modal depth of each assessment unit. The method is incorporated into a spreadsheet software system (DEEP) that can be easily expanded to include any number of depth slices.

Future Activities

At the end of Phase 2 of this project, results from the first six tasks will be integrated in order to summarize directions for future study. Questions to be answered include: What can we learn about deep gas accumulations Worldwide to improve our capacity to recover deep gas in the U.S. Data on deep gas from the other countries will provide the basis for this summary. What regions of the U.S. deserve the most attention with respect to future deep drilling? Work will also include final prioritizing of the deep parts of as-yet-undefined basin-centered deep gas plays.

For Phase 2 of this project, the following activities will be undertaken:

1. High priority deep basin-centered gas accumulations will be evaluated in further detail in order to define plays for each of them (Task 1).
2. All gas plays in the U.S. (including unconventional plays) will be evaluated on the basis of uncertainty as determined by the range of fractiles in the probability distributions for undiscovered resources (Task 2).
3. Deep Morrow sandstone reservoirs will be analyzed for the Gas Effect and Gas Production Index using gamma ray, neutron, and density logs (Task 3).
4. Deep gas plays will be evaluated for (a) potential gas-oil ratios for resource assessment and (b) the role of water in the generation of deep gas (Task 4).
5. Selected Gulf Coast region deep gas plays will be re-evaluated for resource assessment purposes. Plays will be analyzed for their continuous-type accumulation characteristics (Task 5).
6. Assessment unit resource estimates for about 100 provinces Worldwide will be subdivided into depth increments as data become available from the U.S. Geological Survey World Energy Assessment Project.

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FIGURE CAPTIONS

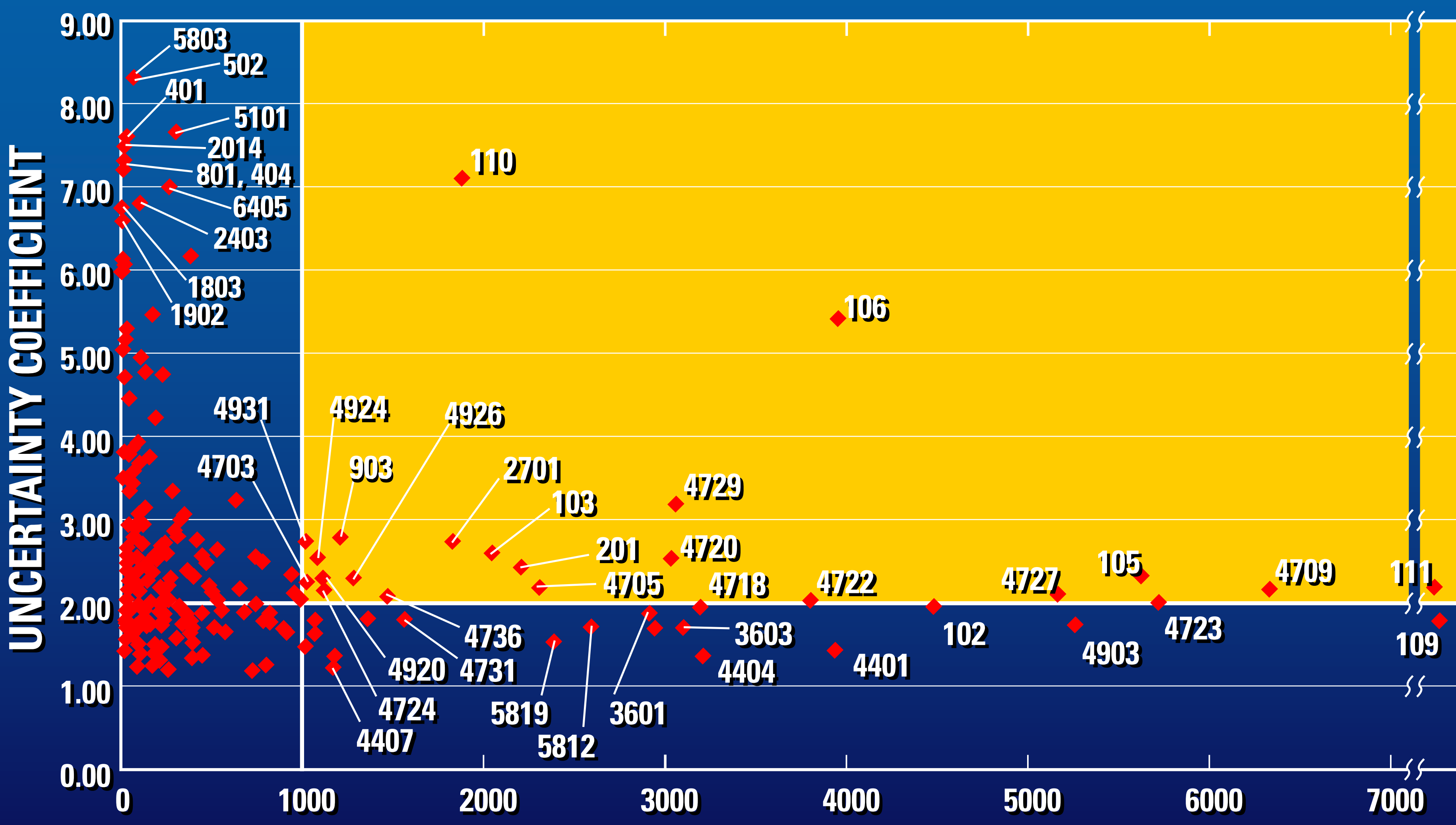
Figure 1. Generalized map of conterminous U.S. and Alaska showing basins containing sedimentary rocks deeper than 15,000 feet (about 4.5 km). Shaded areas represent entire basins.

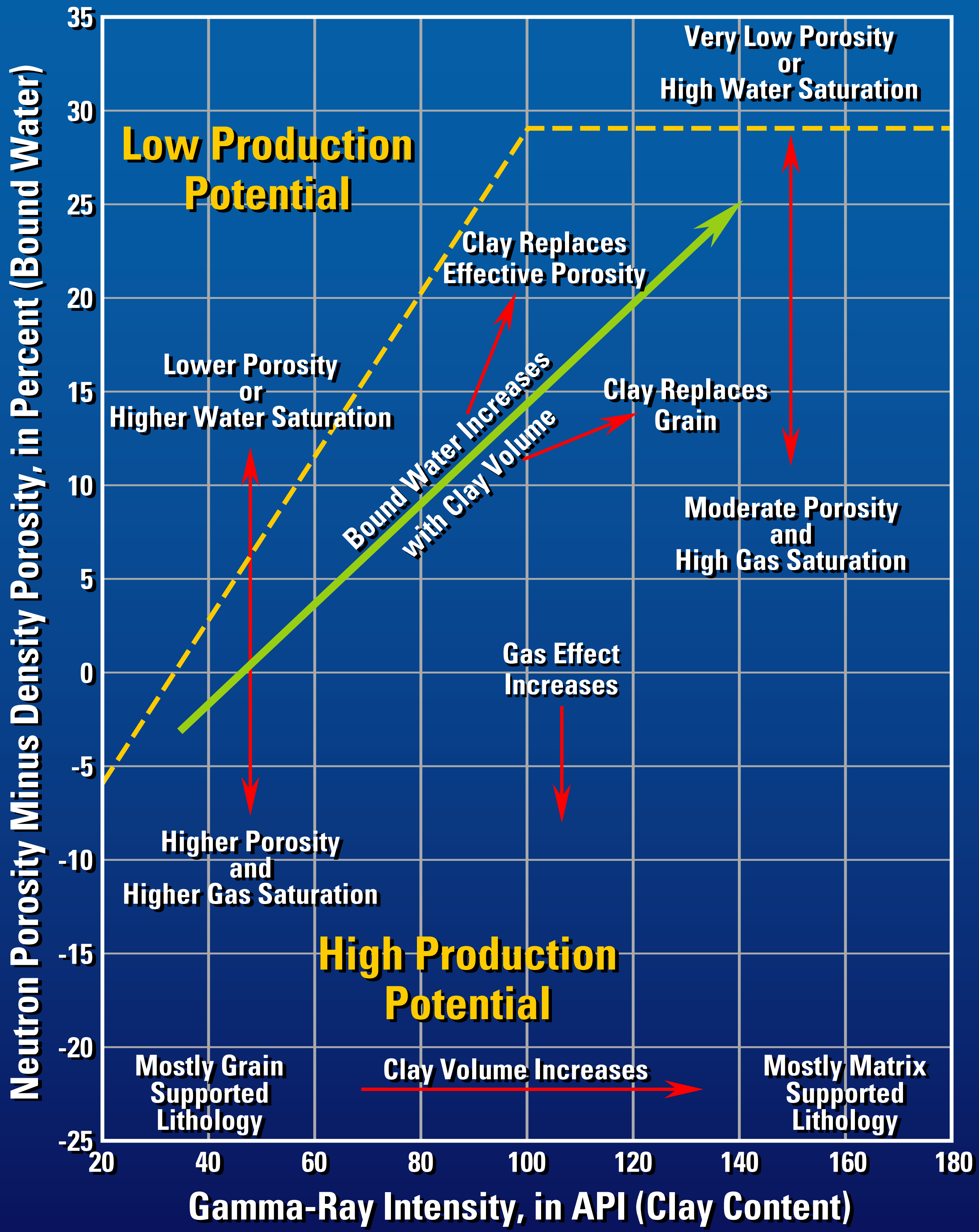
Figure 2. Plot of uncertainty coefficient versus mean non-associated undiscovered conventional gas (in billions of cubic feet) for 236 gas-bearing plays from the USGS 1995 National Petroleum Assessment. Example plays identified by number. Refer to Gautier and others (1996) for play numbers. Shaded area represents plays with UC greater than 2.00 and mean undiscovered resource greater than 1,000 Bcf of gas. Play numbers 111 (23.8 Tcf of gas) and 109 (13.3 Tcf of gas) are off scale with respect to horizontal axis.

Figure 3. Summary crossplot of neutron porosity minus density porosity versus gamma-ray intensity, showing relative variation in porosity, water saturation, clay volume, bound water, and production potential, with plotted position of interval data. Heavy solid line is regression line of Figure 4 of Hester (1999). Dashed line is zero-production baseline of Figure 5 of Hester (1999).

Columbia River plateau
Montana thrust belt
Western OR-WA Tertiary basins
Williston
Crazy Mts.
Big Horn
Hornbrook
WY-UT ID thrust belt
SRP
W
PR
Appalachian
Sacramento
Green River
Hanna
Michigan
Georges Bank
Central Coastal basins
San Joachin
Uinta
Piceance
Wash.
Illinois
Baltimore Canyon trough
Raton
Midcontinent Rift
Ventura
Los Angeles
Salton Trough
Al
Anadarko
Arkoma
Carolina trough
Black Warrior
Permian
N. Slope basins
Central Alaska basins
Norton Basin
Cook Inlet basin
Blake Plateau basin
Gulf Coast
Yakutat
Bristol Bay
500 KILOMETERS

HIGH PRIORITY GAS PLAYS FOR RE-EVALUATION





Very Low Porosity
or
High Water Saturation
Low Production
Potential
Clay Replaces
Effective Porosity
Lower Porosity
or
Higher Water Saturation
Bound Water Increases
with Clay Volume
Clay Replaces
Grain
Moderate Porosity
and
High Gas Saturation
Gas Effect
Increases
Higher Porosity
and
Higher Gas Saturation
High Production
Potential
Mostly Grain
Supported
Lithology
Clay Volume Increases
Mostly Matrix
Supported
Lithology
35
30
25
20
15
10
5
0
-5
-10
-15
-20
-25
20
40
60
80
100
120
140
160
180
Neutron Porosity Minus Density Porosity, in Percent (Bound Water)
Gamma-Ray Intensity, in API (Clay Content)

Table 1. List of basins/areas in each region of the U.S. with new potential basin-centered gas accumulations with respect to the USGS 1995 National Petroleum Assessment (Gautier and others, 1996). Ranking of each basin as high, medium, or low potential in parentheses is based on criteria discussed in report. Comments included with respect to evaluation in 1995 USGS National Assessment.

Alaska Region

Cook Inlet basin (medium-high)-- no continuous-type plays identified in 1995

Western Colville-Central Alaska basins (medium-high)—no continuous-type plays identified in 1995

West Coast Region

Columbia basin (medium)—one continuous-type gas play assessed in 1995

Willamette-Puget Sound trough (medium)-- one continuous-type gas play assessed in 1995

Hornbrook basin (low-medium)-- no plays defined in 1995

Los Angeles basin- seven conventional plays assessed (low)—one continuous-type gas play defined but not assessed in 1995

Salton Trough (low)-- no continuous gas plays defined in 1995

Rocky Mountains-Northern Great Plains Region

Hanna basin (high)-- no continuous-type gas plays defined in 1995

Snake River downwarp (low)-- no continuous-type gas plays defined in 1995

Midcontinent Region

Anadarko basin (high)-- two deep conventional plays assessed, one continuous-type play defined in 1995

Arkoma basin (medium)-- no continuous-type gas plays defined in 1995

Midcontinent Rift (low-medium)-- no continuous-type gas plays defined in 1995

Gulf Coast Region

Western Gulf basin Austin Chalk (high)-- updip continuous-type Austin oil play assessed; no continuous gas plays identified in 1995

Louisiana-Mississippi Salt basins-Cotton Valley/Travis Peak (high)— 44 deep conventional gas plays and one continuous gas play assessed in 1995

Eastern Region

Black Warrior basin (medium)-- four conventional plays assessed, but no continuous-type gas plays defined in 1995